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January 31, 2008

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007

Re: Docket No. E-01345A-05-0674

Pursuant to Decision 68645, APS is filing the 2007 annual report on the residential TOU (time-of-use) rates ET-2 and ECT-2. The Decision requires that by each January 31st from the date of the order, APS shall file with Docket Control annual reports that detail the summer and winter load shapes of the participants in the experimental rates, the number of customers taking service on these experimental rates and the amount that customers saved relative to non-time-of-use rates.

In addition to detailing the summer and winter load shapes of customers participating in the new schedules and the required data on the number of participating customers and revenue savings relative to non-time-of-use rates as required by Decision No. 68645, this year's report has been expanded to include information related to APS' system load shape and descriptions of potential alternative TOU options that are under consideration for future filing by APS. The potential pricing options includes a residential "super-peak" rate and a (Critical Peak Pricing) CPP offering for general service customers. This expanded report is also being filed in the generic docket (E-01345A-07-0448) established for time-of-use rates.

If you have any questions on the enclosed report, please to call David Rumolo at (602) 250-3933.

Sincerely,

Barbara Klemstine

Barbara Klemstine

Attachment

CC: Ernest Johnson
Terri Ford
Brian Bozzo

Arizona Corporation Commission
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JAN 31 2008
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Arizona Public Service Company
Residential Time-of-use Rates ET-2, ECT-2
Compliance Report, Decision No. 68645, Docket No. E-0135A-05-0674
Initial Filing, Docket No E-0135A– 07-0448
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I. Summary and Conclusions

The Arizona Corporation Commission (ACC) approved two new residential time-of-use (TOU) rates for Arizona Public Service (APS) in Decision No. 68645. The new rate schedules, designated Schedule ET-2 and Schedule ECT-2, became effective in July, 2006. The rates differ from APS' then-existing TOU rates, ET-1 and ECT-1R, by the fact that the on-peak periods of the new rate schedules are 12:00 PM to 7:00 PM week days compared to 9:00 AM to 9:00 PM. The new rate schedules also provided that certain holidays are designated as off-peak periods.

There are currently over 50,000 customers participating on the new TOU rate schedules. For a new voluntary rate schedule, such high participation is notable. To provide some perspective, customer participation in these new rate schedules alone would rank in the top 10 utility TOU programs in the United States, without even considering that there are over 400,000 customers served on Schedules ET-1 and ECT-1R.

While customer acceptance of the new TOU rates has been successful, the evidence to date does not indicate that customers' load patterns have changed significantly compared to customers on the vintage TOU rates. Specifically, one of the concerns raised when ET-2 and ECT-2 were approved was that shifting of usage to the post 7:00 PM period might result in a shifting of the APS system peak to a later time but would not yield a reduction in the size of the peak. Based on the data displayed in this report, load patterns for customers on both TOU rates are similar.

The acceptance level of the new rate combined with the wide acceptance by APS customers of the vintage TOU rates indicates that APS residential customers are aware of the benefits of TOU pricing. To further encourage the reduction of load during the peak periods, and offer potential additional savings to customers that are willing and able to shift their consumption, APS is considering offering another variation of TOU rates to residential customers, called a "super-peak" rate. This rate would feature a three-tiered pricing structure during the peak summer months. An off-peak rate would be the lowest priced time period, an on-peak price period would be higher than the off-peak period and a third tier would be the most expensive and would be in effect during a portion of the summer season on weekdays during the three hour window when the APS system peak typically occurs and resources needed to serve customers are the most expensive.

II. Background of Time-of-Use Rates

The genesis of most TOU rates can be traced to the Public Utilities Regulatory Policy Act of 1978 (PURPA) that required state regulators to consider six rate design standards. The standards were: 1) rates should be cost of service based, 2) declining block rates should be eliminated, 3) rates should be offered based on the time of day of consumption, 4) rates should reflect seasonal cost differences, 5) interruptible rates for industrial and commercial customers should be considered, and 6) load management options should be considered. In November 1981, ACC Decision No. 52593 implemented the PURPA standards and the introduction of APS's residential TOU rates.

Since the introduction of TOU pricing by APS, the program has grown to one which sees the most wide-spread use of residential TOU in the country. In its 2006 report on Demand Response and Advanced Metering, the Federal Energy Regulatory Authority (FERC) noted that only one utility had more total TOU customers than APS. Upon closer examination it was determined that that the Oklahoma Gas and Electric program that was described as TOU actually reflected only seasonal price differentiation (which even APS' non-TOU rates reflect) and not diurnal price differentiation.

III. Time-of-Use Pricing Theory

TOU pricing is an attempt to provide price signals to customers that reflect the variation of costs incurred by the utility. The objective of TOU pricing is to encourage customers to shift load from high-cost periods to low-cost periods through price signals. Costs, especially marginal costs, vary over the hours of the day as well as on a seasonal basis. For summer peaking utilities such as APS, the highest cost hours are during the time of peak summer usage.

During the peak times, customer load requirements are met through the use of peaking plants and market purchases that carry the highest marginal costs. Peaking plants tend to be less economic than base load generation such as coal or nuclear plants or shoulder units such as combined cycle plants, and ideally the costs of a peaking unit should be recovered in the hours in which the units are required. This may be as few as 100 hours per year.

The costs of base load units are spread over the entire 8,760 hours of the year. In general, winter average costs are lower because more of the customers' total requirements can be met from base load generation. Thus, the price signal that the customer receives should reflect higher cost during summer on-peak hours and lower costs during off-peak hours. The price signals can be in the form of higher per kWh charges, higher demand (kW) charges, or both.

TOU pricing is beneficial to the utility as well as to customers. The opportunity to shift load from the high cost periods to low cost periods consistently presents the long-term benefit of deferring investment or costs for capacity. From the perspective of customers, TOU pricing provides the opportunity for individual customers to save money. However, it does not automatically result in savings for individual customers. Customers need to react to the price signals and take steps to reduce or shift load to the off-peak hours. Economic research indicates that there is some level of price elasticity for residential customers. Therefore, on/off peak price differentials are an important factor in TOU rate design. If price differentials are not significant, less shifting will occur.

IV. Forms of Time-of-Use Pricing

Historically, TOU pricing in the electric utility industry has focused on seasonal and daily price plans and combinations of the two. For example, APS has seasonal price differentiation in most rate schedules. Daily price differentials are found in several residential rate schedules, e.g. ET-1, ECT-1R, ET-2 and ECT-2. TOU rate options are also available to general service customers. Due to the need to meet growing loads, utilities are beginning to pilot new TOU pricing plans. These plans include critical peak pricing (CPP) plans and real-time pricing (RTP) plans.

CPP plans are pricing plans that include high per-unit prices during certain critical peak periods. The prices are generally preset. The critical peak periods, which are typically 100 hours per year, are the times when the most expensive resources are called upon or when operations or reliability concerns, such as transmission constraints, are faced.

CPP plans have several variations including fixed period CPP (CPP-F) in which the time and duration of the critical pricing periods are set, and customers are notified that the CPP is in effect on a day-ahead basis; variable period CPP (CPP-V) in which the critical events are called on a "day-of" basis, and the prices, time and durations are not pre-set; variable peak pricing (VPP) in which off-peak and shoulder pricing is predetermined, but on-peak pricing is tied to wholesale; and Peak Time Rebate (PTR) pricing under which customers are on traditional fixed pricing but receive rebates during critical times based on demonstrated load reductions.

In addition to critical peak pricing plans such as CPP-F and PTR, there can be hybrid critical peak plans such as a super peak pricing plan. This plan blends the features of "typical" TOU pricing plans with CPP elements. For example, a high price can be ascribed to consumption during the times when the utility's highest peak occurs during the highest cost season. For APS, the super peak pricing would occur during a subset of the current peak period hours. For example, during the months of June, July, August, and September, the super peak period would occur during the late afternoon hours. As will be discussed later in this report, the APS system exhibits a fairly broad peak period during summer afternoons but the time of system peak is generally between 4:00 and 7:00. The value of customers consistently shifting load away from these peak hours could be significant in terms of reduced market purchases or capacity requirements, and provides more ability for customers to manage consumption on a more consistent basis than come CPP programs.

RTP plans are pricing plans in which rates vary continuously throughout the day to reflect hourly resource costs. While RTP provides more pricing data to customers, it requires significant infrastructure, both to calculate the pricing signal in real time, to communicate that information to customers, and to meter and bill the resulting consumption by the customer. As a result, RTP is better suited for organized markets (i.e. RTO's) where hourly day-ahead and real-time price signals are determined through a liquid and transparent market mechanism. Arizona does not have an RTO. Therefore, the Company has placed lower priority on developing real time pricing programs compared to the other pricing options discussed. Moreover, unlike preset times or lower hours, RTP is generally much harder for customers to manage. For example, many residential customers can alter consumption patterns to do laundry or run pool pumps off an established peak pricing period. Fewer customers could meaningfully start and stop laundry or turn pool pumps off and on based on hourly real time price signals. Research confirms that RTP programs generally result in less shifting of customer consumption than other TOU options, and thus make it more difficult for the benefits to offset the infrastructure costs required to implement such a program.

The roll out of alternative TOU pricing is largely dependent on Advanced Metering Infrastructure (AMI) availability and the availability of other enabling infrastructure additions. While traditional TOU pricing can be accomplished with readily available TOU electronic meters, CPP plans require interval data so that a customers' consumption during the CPP events can be identified and communications systems to notify customers of CPP events. Plans such as PTR also require sophisticated analytical tools to project what a customers' load would have been absent the requested curtailment. Also, not all pricing alternatives are suitable for all customer classes. RTP or CPP-V that require customers to react to price "day-of" signals require communications tools and infrastructure that are still in the early stages of development. As discussed above, customers must be able to react to the price signals for the programs to be effective. For example, absent control by a utility or third party, it would be difficult for a residential customer who is not home during the daytime to react to a price signal. Similarly, small commercial customers may have limited ability to react because of the nature of their business operations. Because of these recognized limitations and start-up costs, CPP pricing alternatives are still in an infancy stage. Programs such as the California Statewide Pricing Pilot have been rolled out on a pilot basis with opportunities to revise and amend the pilots as experience with the programs increases.

V. APS System Information

APS System Load

APS serves more than one million customers in 11 of Arizona's 15 counties. Although this provides diversity in customer load characteristics more than two-thirds of APS' residential customers reside in Metro Phoenix. The APS system load shape for the summer peak day is provided below. The hourly values are expressed as a percentage of the peak hourly load, which occurred at 5:00 p.m. As shown, the load at 7 p.m. is still 95.1% of system peak and at 9:00 p.m. is 89.0% of system peak. The various time-of-use hours, 9 to 9 and 12 to 7, are also included. See Graph 1 below. Also for comparison purposes, Table 1 summarizes the avoided generation costs for the summer and winter on and off peak periods. This information is based on forward market prices at the Palo Verde trading hub. Actual wholesale spot prices during specific peak hours can be greater than the average forward prices. For example, hourly spot prices reached $100 per MWH on occasion in the summer of 2007. The western wholesale electricity market is currently subject to a soft price cap of $400 per MWH, which means that hourly spot prices exceeding $400 must be justified to the Federal Energy Regulatory Commission.

Graph 1.

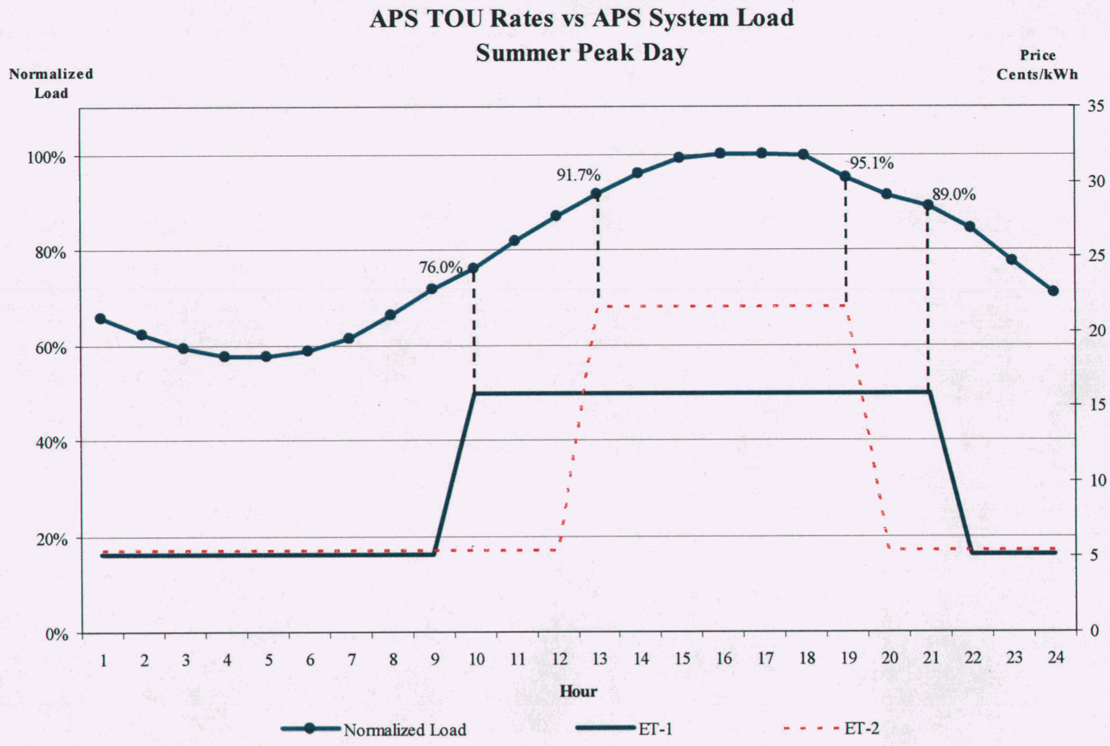


Table 1.

2007 Avoided Generation Costs
Cents/kWh

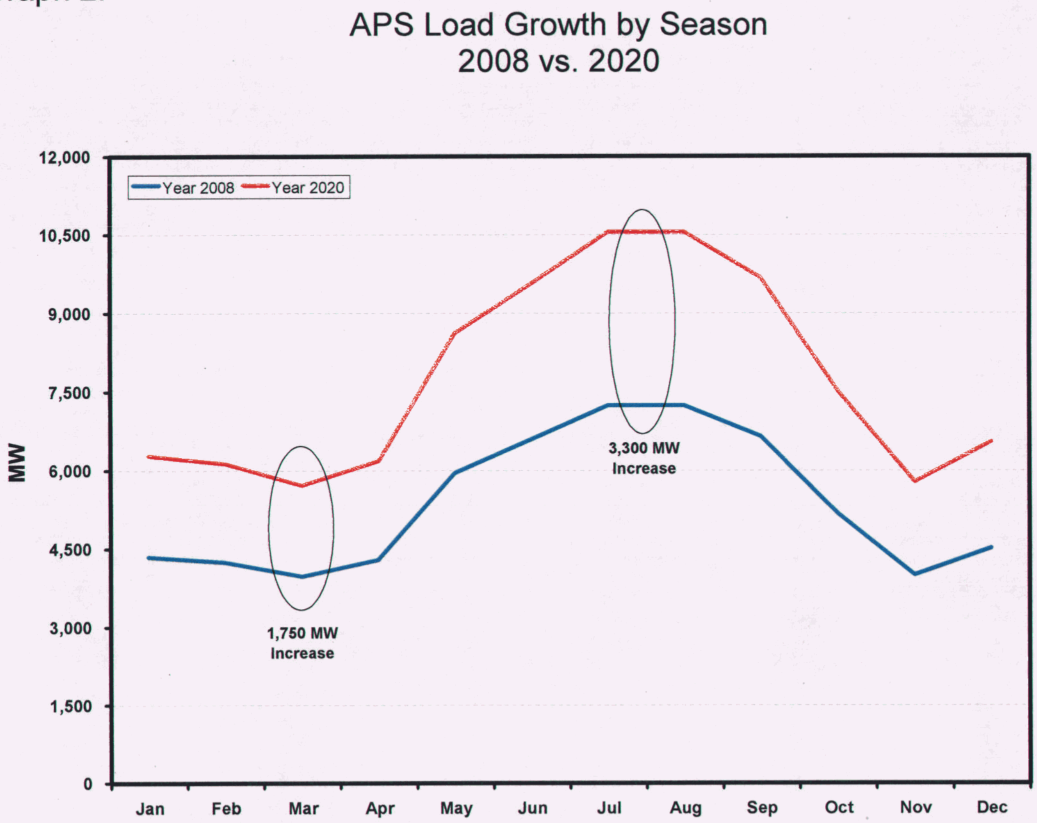
	Summer	Winter
On Peak	7.630	5.330
Off Peak	7.510	5.770

Load Growth

The Company is forecasting an annual growth rate for system load of over 2.5% over the next 20 years. Peak demand is estimated to grow by over 3,800 MW by 2020 and by almost 6,400 MW by the year 2027. This equates to annual growth in peak demand of approximately 300 MW per year.

On a seasonal basis, APS load requirements are forecasted to grow at a much more rapid pace during the summer months as in all other months. In fact, as can be seen in Graph 2 below, the summer peak demand will increase at almost twice the rate as the peak demand during the non-summer season. This is due to the weather-sensitive nature of APS's customer electricity requirements.

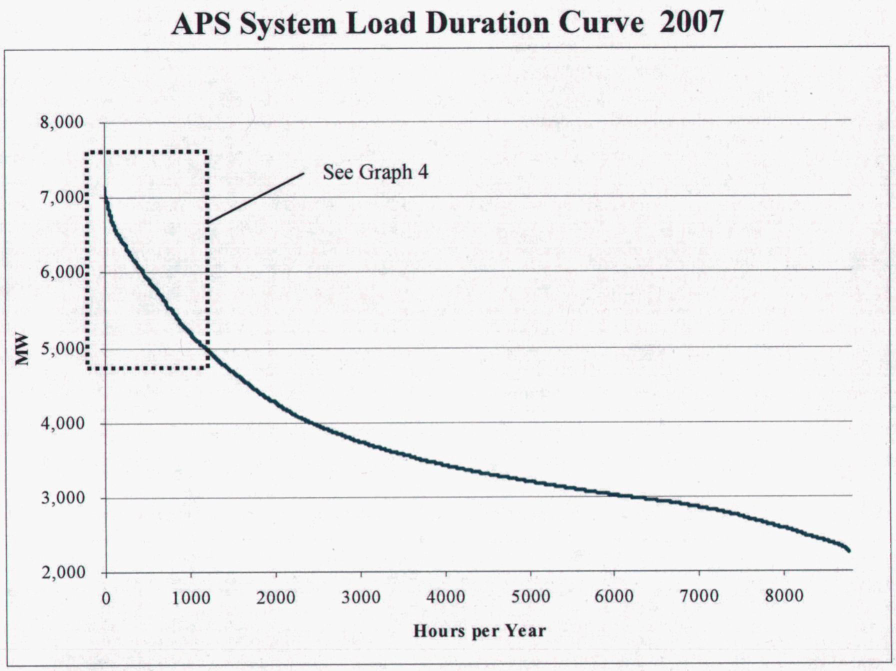
Graph 2.



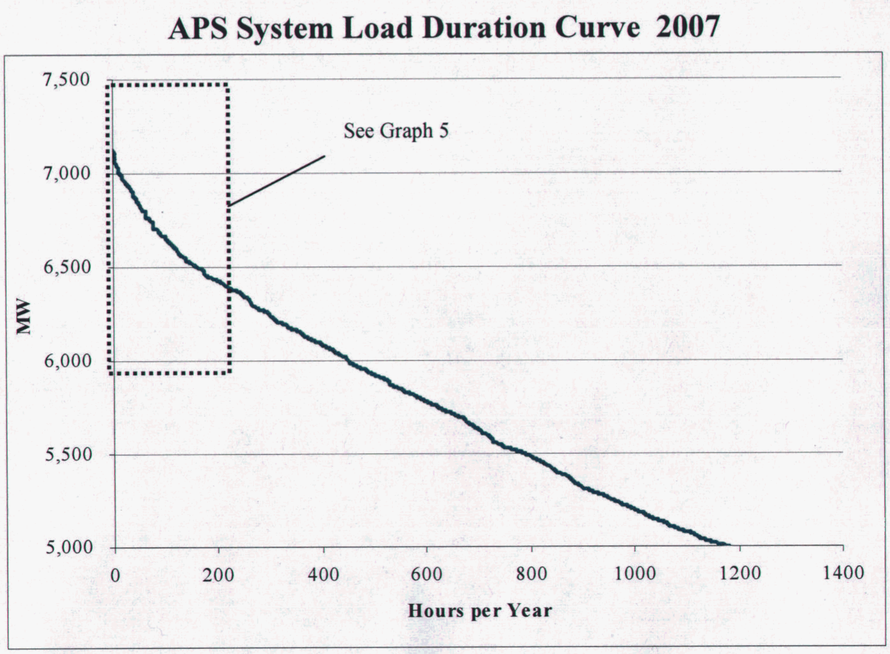
Load Duration Curve

The Company's load duration curve for 2007 is provided in Graphs 3 - 5. This information depicts the number of hours in a year (X axis) that the system load reached a particular MW level (Y axis). As shown, a significant amount of peak load occurs in only a relatively low number of hours per year. In fact, approximately 170 hours in the year had loads that were within 10% of the system peak hour.

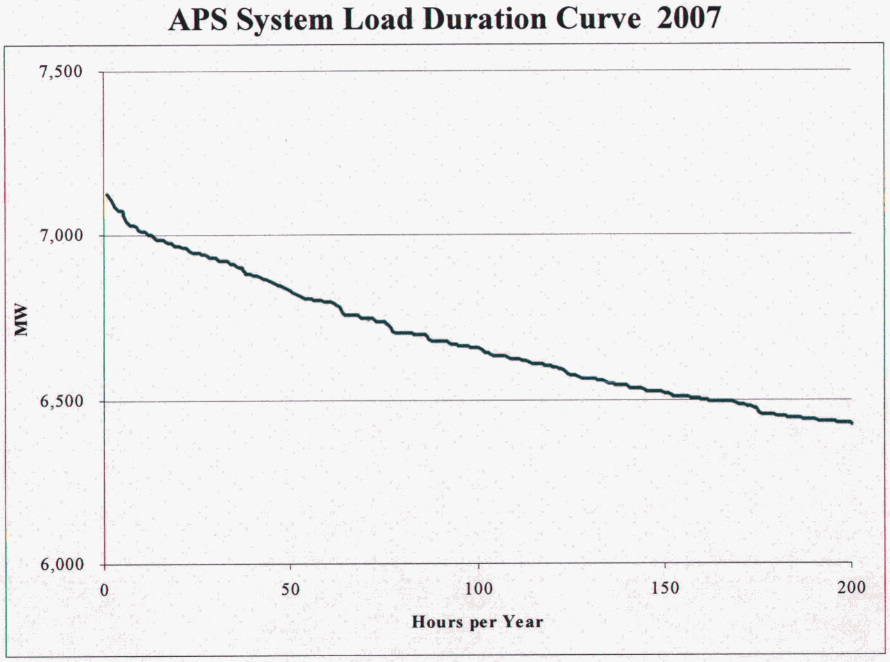
Graph 3.



Graph 4.



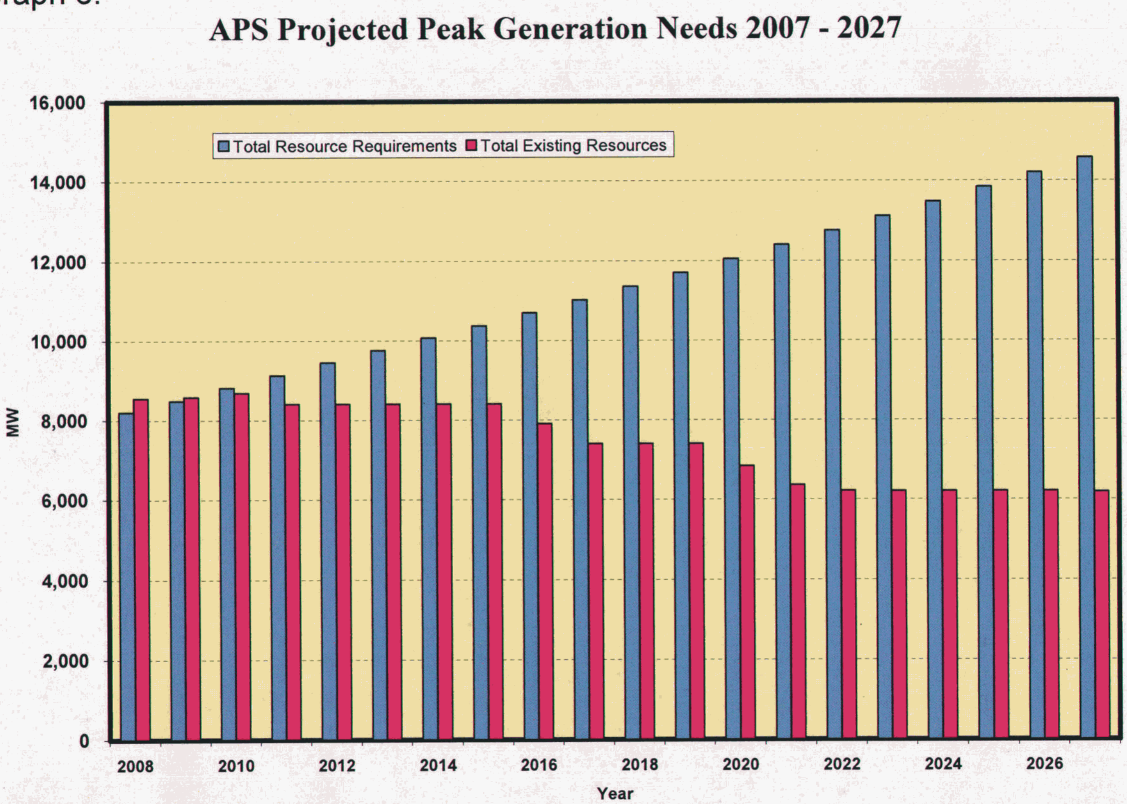
Graph 5.



APS Generation Resources

APS currently has over 6,100 MW of generating resources and acquires nearly 2,000 MW of additional supply through purchased power agreements. Over the next 20 years the company will need the addition of nearly 8,300 MW of new generation (see Graph 6).

Graph 6.



VI. Existing APS Time-of-Use Rate Offerings

Background

In July 2006, APS implemented the "series-2" residential time-of-use rate schedules, ET-2 and ECT-2, which have an on-peak period of noon to 7:00 p.m. Rate schedule ET-2 has on-peak and off- peak energy charges. Rate schedule ECT-2 has an on-peak demand charge in addition to on-peak and off-peak energy charges. These rates are offered in addition to the Company's "series-1" residential time-of-use rate schedules, ET-1 and ECT-1R, which have an on-peak time period of 9:00 a.m. to 9:00 p.m.

Status

As of December 2007, 40,677 customers are participating in the ET-2 rate. The year over year increase in customers on ET-2 was 14,815, a growth rate of 98.7%. 11,879 customers are participating in ECT-2 rate. Similarly, the increase in year-over-year customer participation in ECT-2 was 4,009, which is a growth rate of 132.0%. Overall the series-2 time-of-use rates had a total participation level of 52,556. This represents a year–over-year increase in customer count of 18,824, which is a 104.3% increase in the total customer participation level.

Load Shapes

Average daily load shapes for the winter and summer seasons were derived from recorded load research data. The summer seasonal load shapes consist of hourly load data from May 2007 through October 2007. The winter load shape includes data from December 2006 through April 2007 and November 2007. The attached load shapes are provided for weekday and weekend types. For comparison, the load shapes for rate schedules ET-1 and ECT-1R are also provided. See Graphs 7 through 14.

Peak Usage and Shifting

The ET-2 and ECT-2 summer weekday load shapes show a slight increase in usage after 7:00p.m., when the on-peak period expires. Conversely, the ET-2 and ECT-2 summer weekend load shapes show a modest decrease in usage after 7:00 p.m. The ET-1 and ECT-1 show a similar shape around the same hours during the summer weekends. This impact is more pronounced for the ECT-2 rate, which has an on-peak demand charge, in addition to on-peak and off-peak energy charges (as shown in Table 2).

The percent kWh consumed during the noon to 7:00 p.m. on peak period for the summer season was 24.7% for ET-2 and 24% for ECT-2, based on load research data. By comparison, the summer on-peak usage for the same time period (noon to 7:00 p.m.) for rate schedule ET-1 and ECT-1R, which have a 12 hour on-peak period, is 25.5% and 24.9% respectively. This suggests that although the on-peak periods differ between the series-1 and series-2 time-of-use rates, the participants of the series-2 time-of-use rates are displaying roughly the same on-peak consumption pattern (+/- 1%) and similar shifting of energy to the off-peak period when compared with the series-1 time-of-use rates.

Table 2.

Peak Consumption
(12pm to 7pm)
Time-Of-Use Rates

Rate	On-peak Usage – Summer	On-peak Usage – Winter
ET-2	24.7%	17.9%
ECT-2	24.0%	18.8%
ET-1	25.5%	17.1%
ECT-1R	24.9%	22.0%

1. ET-1 and ECT-1R usage based on same on-peak hours as ET-2 and ECT-2.

Variation in Customer Usage

The Company also assessed the variation in individual customer usage for each hour, as compared to the class average usage. We computed a specific measure of usage variation known as the coefficient of dispersion, or COD.[1] The findings are displayed in Table 3 and Graphs 15 through 20. It shows that the customers' load variation becomes lower as the on-peak period progresses from 12:00 noon to 9pm for both ET-1 and ET-2 customers.

Table 3.

Summer Variation (COD)
Time-Of-Use Rates
(ET-2 and ET-1)

Rate	12 noon COD Summer	7pm COD Summer	9pm COD Summer
ET-2	25.0 %	21.1 %	20.9 %
ET-1	34.0 %	28.5 %	24.9 %

1. The COD values displayed are an absolute value.

1.

$$\mathrm{CoD} = \frac{1}{n}\sum_{i=1}^{n}\left|\frac{x_i - M_e}{M_e}\right|$$

Where, M_e = Median Value

Customer Bill Savings

As depicted in the table below, customer savings was significant across both series of TOU rates when compared to the same usage pattern under the traditional E-12 rate. This is largely due to the customers' ability to shift load to off-peak periods in order to alleviate higher on-peak charges. Total customer bill savings compared with a non-time of use rate, E-12, was $11,015,000 for ET-2, and $6,028,000 for ECT-2. The combined savings for both rates was $17,043,000 or 21.8% compared to non-TOU rate schedule E-12. The savings are calculated off the base bill without any adjustment, taxes or other fees. See Table 4.

Table 4.

Customer Bill Savings
Time-of-use Rates
(ET-2 and ECT-2)

Rate	Average 12 ME Customers	Bill Savings compared with non-TOU rate, E-12	Average % Bill Savings per customer, compared with E-12
ET-2	27,760	$ 11,015,000	14.7%
ECT-2	6,323	$ 6,028,000	29.0%
Total	34,083	$ 17,043,000	21.8%

1. ET-2 and ECT-2 savings derived from bill calculations based on actual usage data.
2. Results for December 2006 through November 2007

VII. Potential Pricing Alternatives Under Consideration

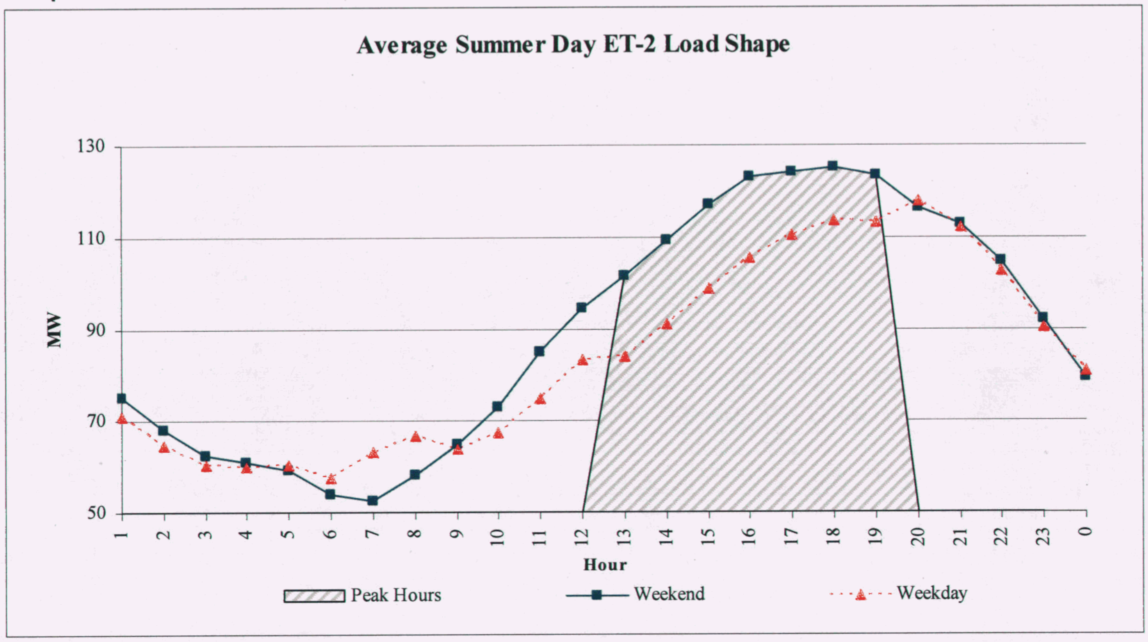
Given the projected growth in the summer peak load, the high usage in a limited number of summer peak hours, and the robust customer acceptance in APS' current time of use programs, the Company is looking to expand its demand response pricing offerings. Currently the Company is evaluating two new pricing proposals for potential implementation. The first new option is a super-peak TOU rate for residential customers. This rate would provide a high super peak price for the highest peak hours of the summer. The super peak period would be limited to only a few hours per day for the hottest summer months. The objective would be to provide a greater incentive for customers to shift away from the highest summer peak hours and thereby provide customers with a greater opportunity to save money on their bills.

The second program under consideration is an experimental critical peak pricing program for general service customers. This program would provide a high price during peak hours of critical days, which are determined by the Company, with day-ahead notification to the customer. This program can help the company target load reduction on a dynamic basis during our summer peak period.

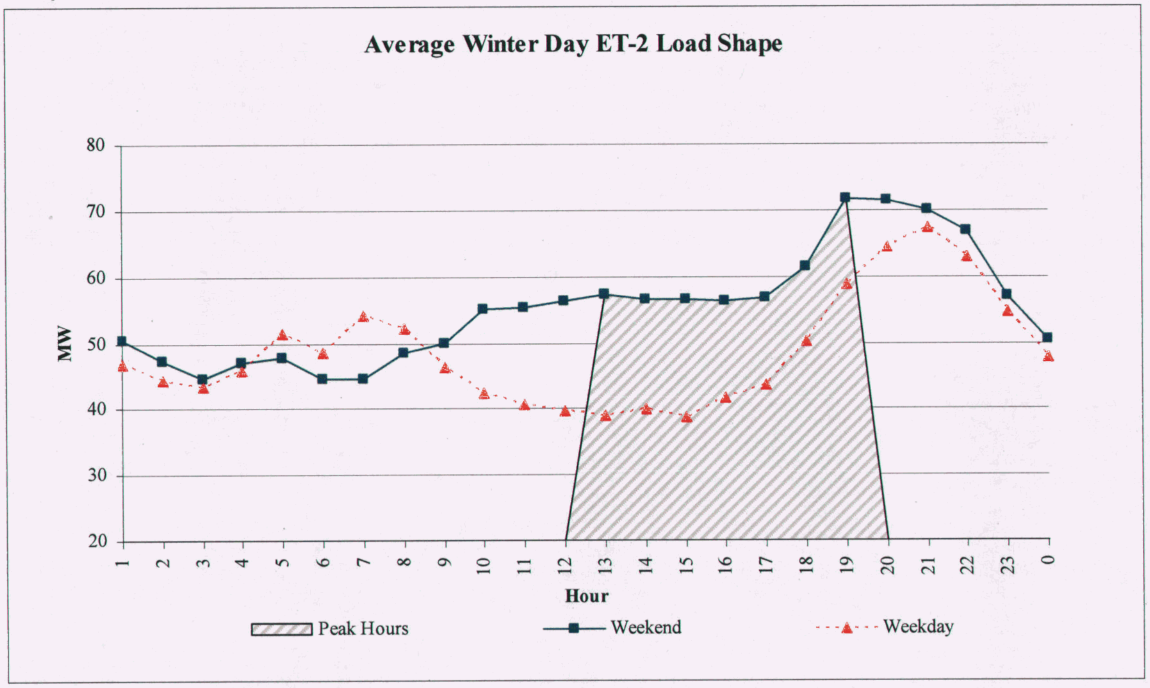
Appendix: LOAD SHAPES

See Section IV. Existing APS Time-of-Use Rate Offerings. Subsection – Load Shapes. The following load shapes display the average summer and winter usage for all customers who take service under the listed TOU rate. Note the general similarites in shape when comparing ET-2 and ET-1 customers.

Graph 7.

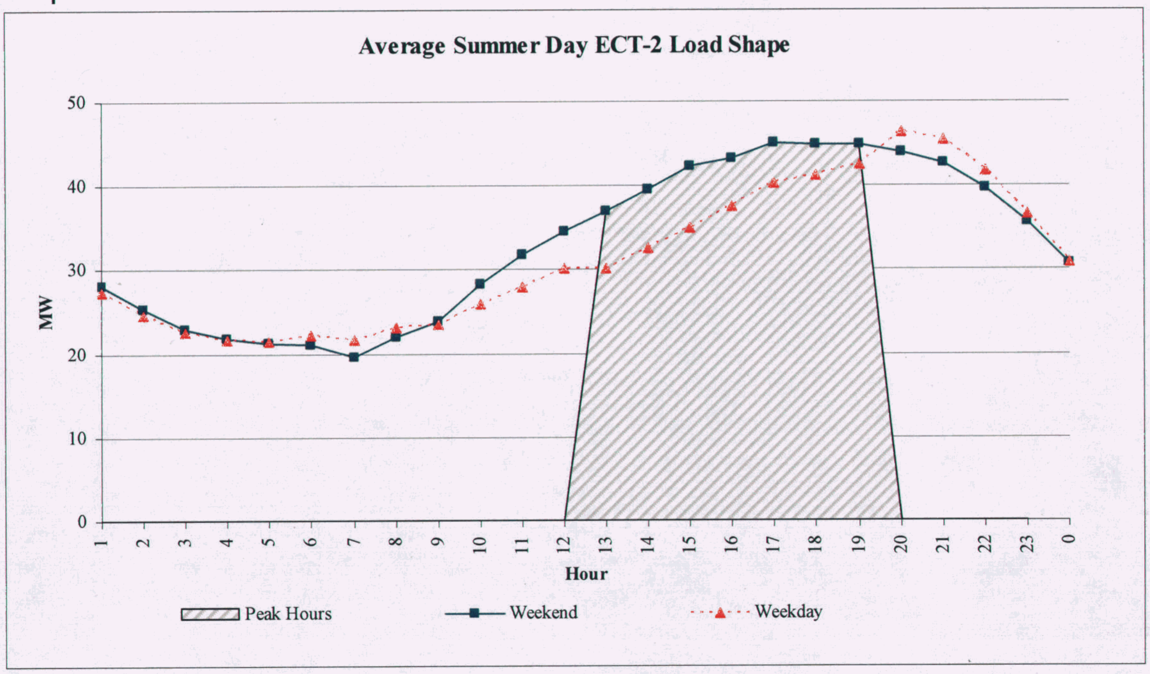


Graph 8.

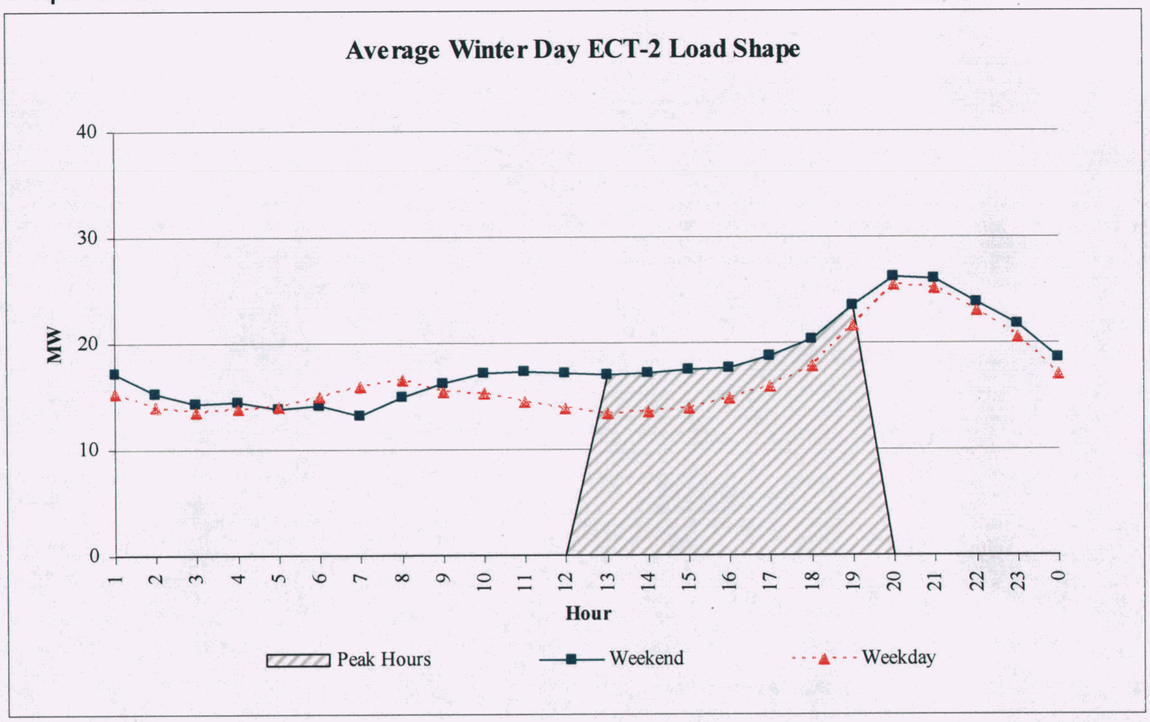


Note: There was not as significant a customer participation size Dec06 – Feb07, then there was for Mar07 – Apr07. Due to this fact the average morning peak was pulled down by the customers usage in March and April. See ET-1 winter peak (Graph 12).

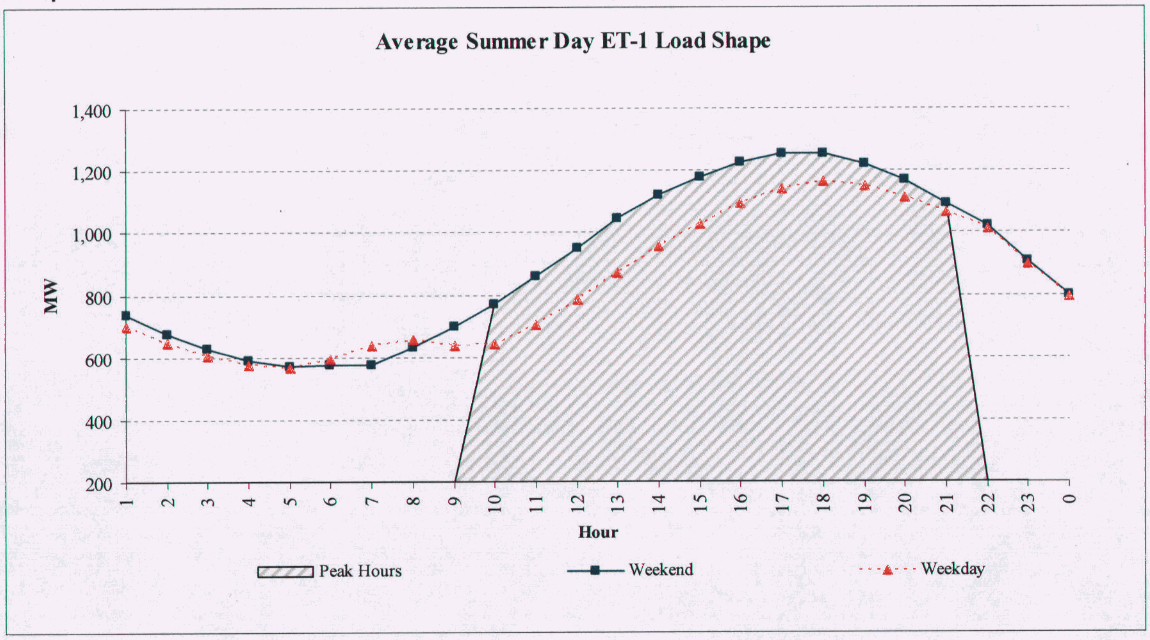
Graph 9.



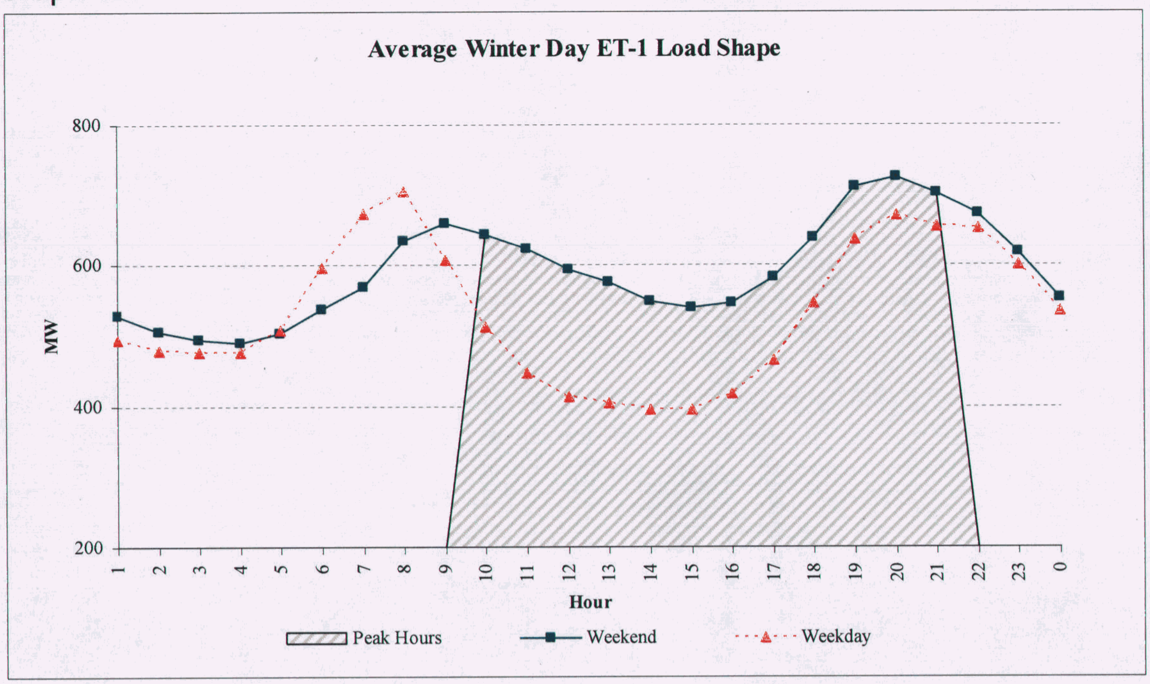
Graph 10.



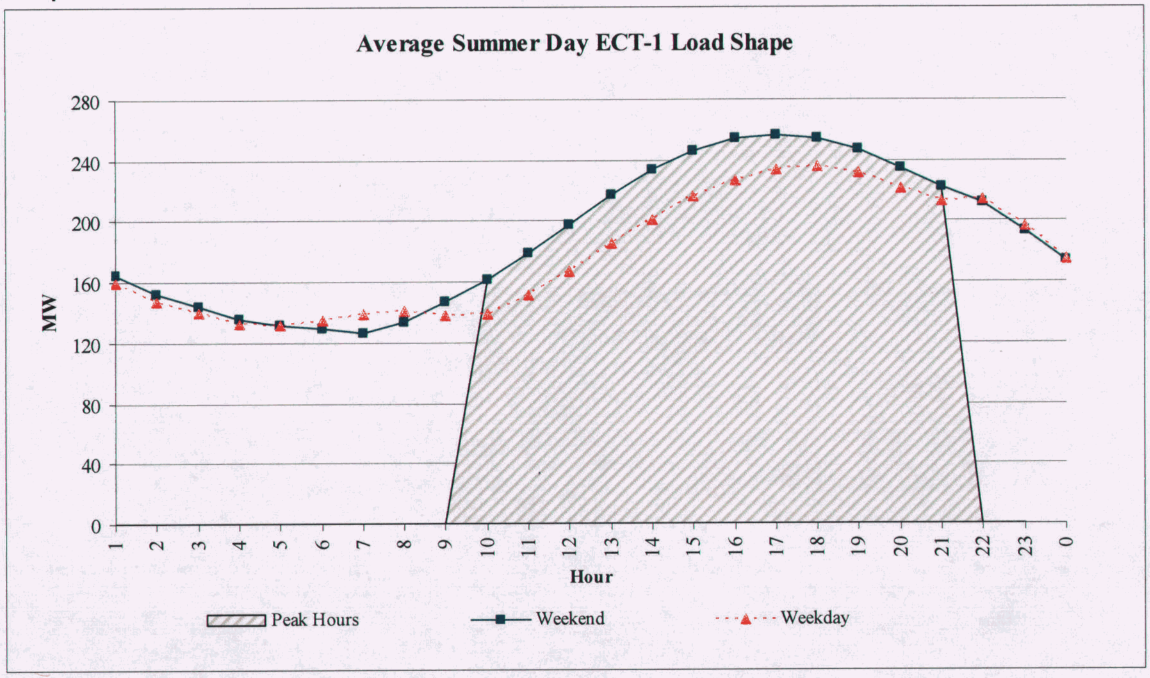
Graph 11.



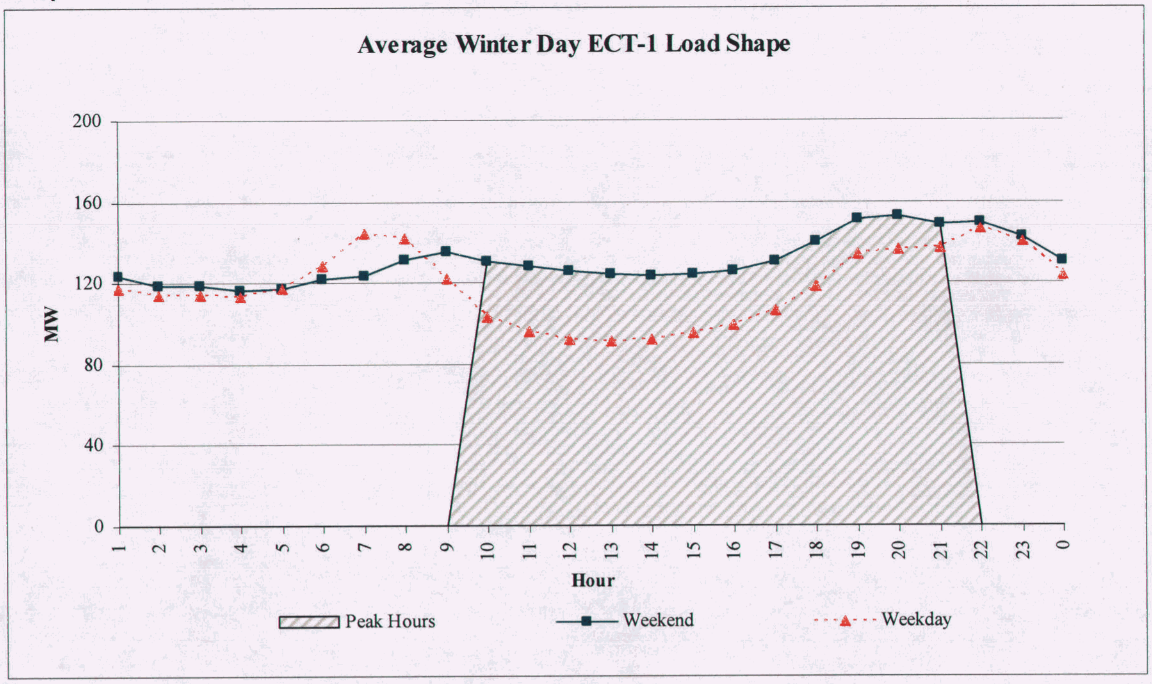
Graph 12.



Graph 13.



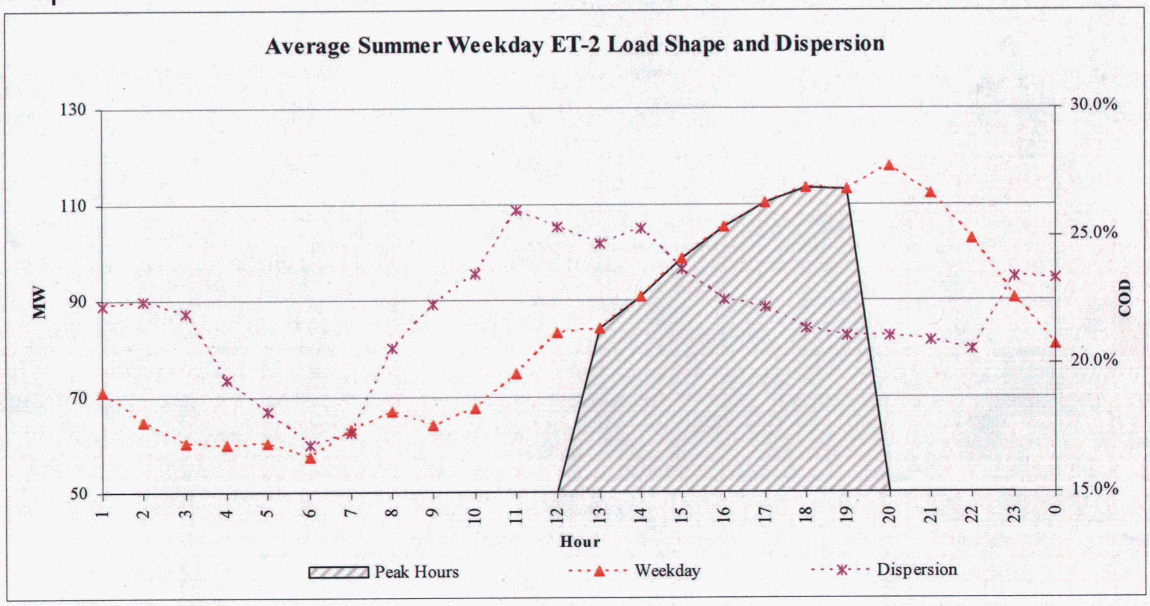
Graph 14.



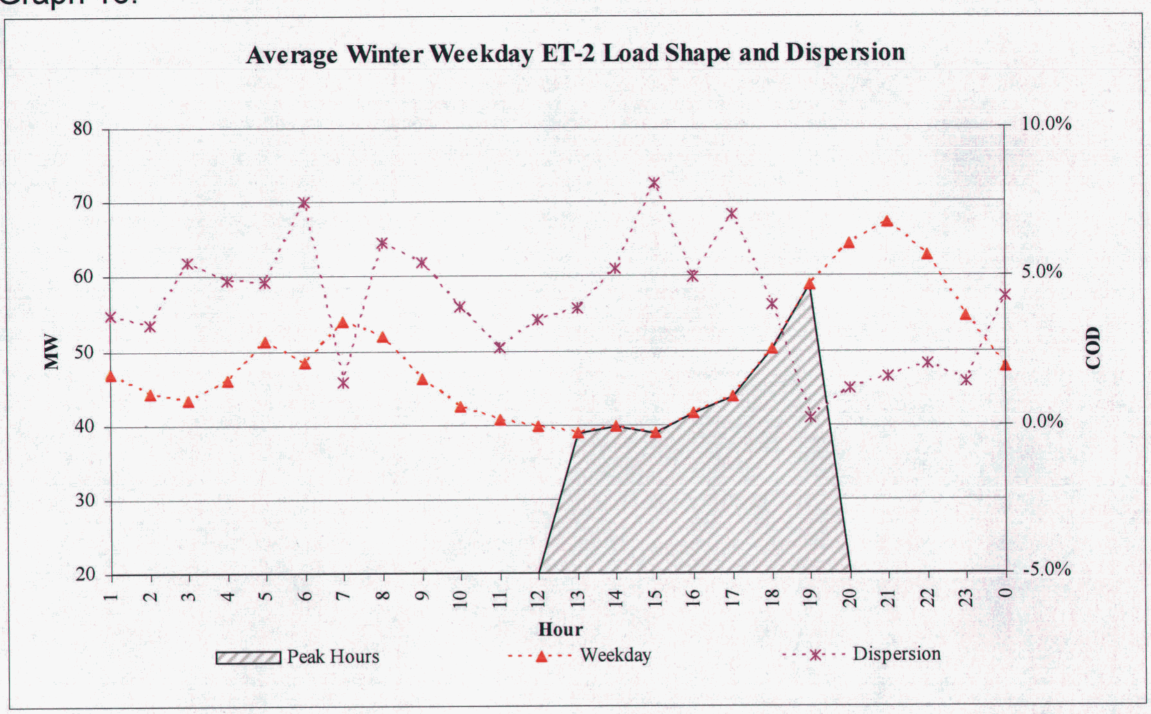
CUSTOMER VARIATION IN LOAD

See Section IV. Existing APS Time-of-Use Rate Offerings. Subsection – Variation in Customer Usage.

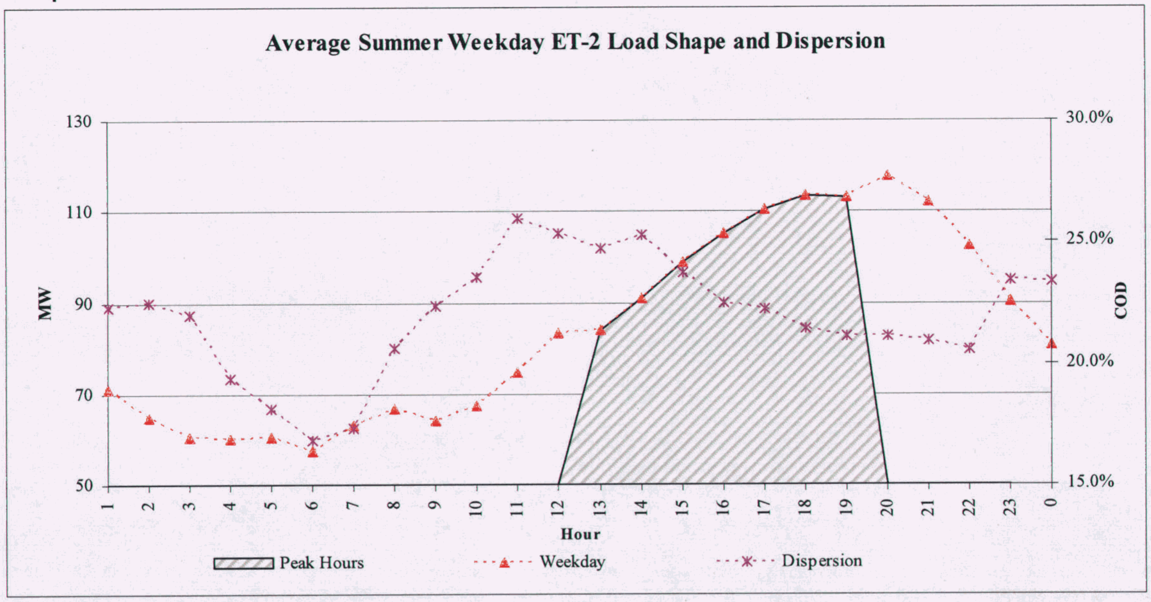
Graph 15.



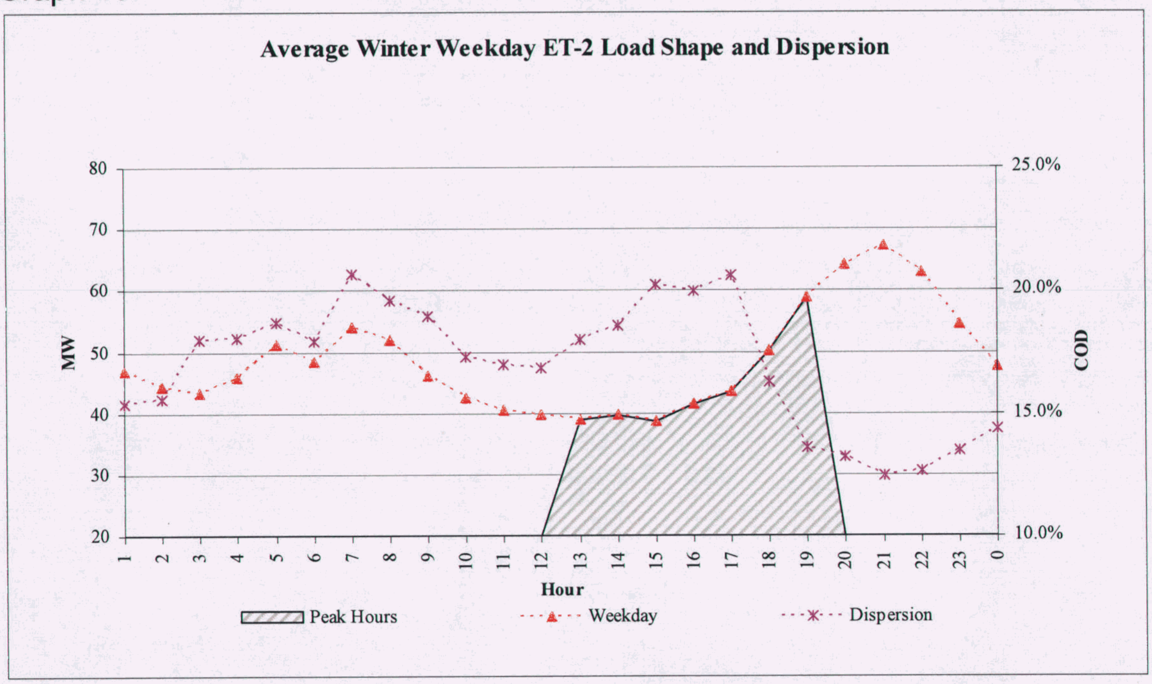
Graph 16.



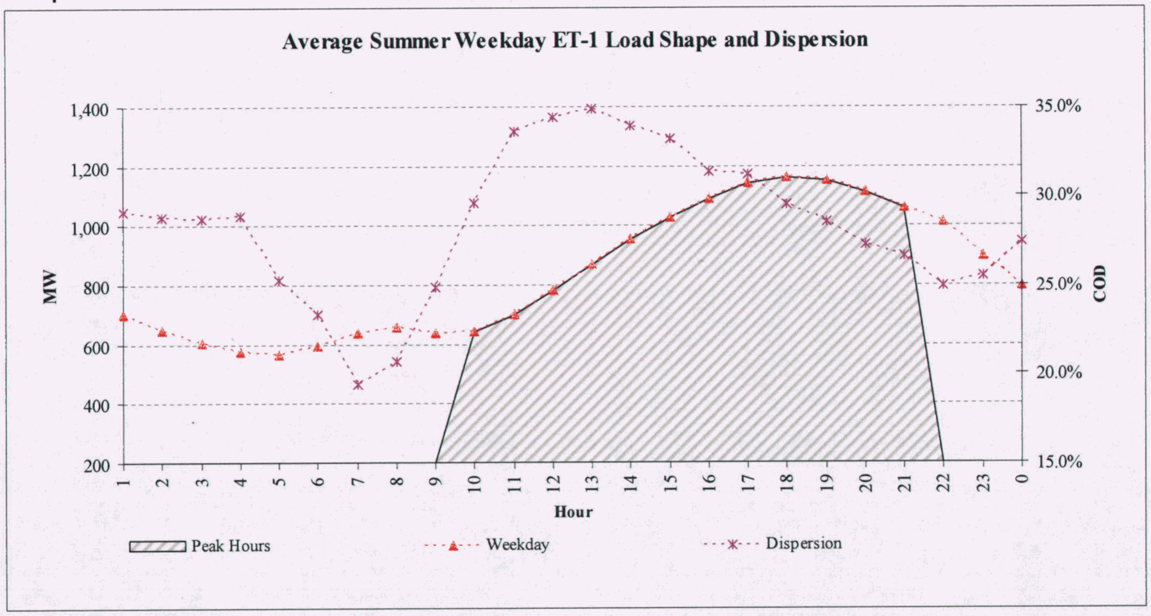
Graph 17.



Graph 18.



Graph 19.



Graph 20.